"बिजनेस पोस्ट के अन्तर्गत डाक शुल्क के नगद भुगतान (बिना डाक टिकट) के प्रेषण हेतु अनुमत. क्रमांक जी. 2-22-छत्तीसगढ़ गजट/38 सि. से. भिलाई, दिनांक 30-5-2001."

पंजीयन क्रमांक
"छत्तीसगढ़/दुर्ग/09/2007-[illegible]."

छत्तीसगढ़ राजपत्र

(असाधारण)
प्राधिकार से प्रकाशित

क्रमांक 5] रायपुर, शनिवार, दिनांक [illegible] जनवरी 2010—पौष 19, शक 1931

Chhattisgarh State Electricity Regulatory Commission

Civil lines, G.E. Road, Raipur - 492 001

Raipur, the 9th January 2010

OBJECTS AND REASON:

No.32/CSERC/2010.—Section 61 of the Electricity Act, 2003 mandates that the appropriate Commission shall specify the terms and conditions for determination of tariff and in doing so shall be guided interalia by multi-year tariff principle. The Chhattisgarh State Electricity Regulatory Commission (Commission - for short) had notified the CSERC (Terms and Conditions of determination of Tariff) Regulations in the year 2006. But these Regulations did not embody the methodologies of multi-year tariff in detail. In para 5.3(h) of the Tariff Policy the general approach to determination of tariff in multi-year framework has been laid down. To meet the object of specifying the terms and conditions for the determination of tariffs according to multi-year tariff principles by the Commission for the supply of electricity to a distribution licensee by generating stations; transmission tariff; tariff for wheeling of electricity; and tariff for retail sale of electricity, this Commission notified the regulations namely CSERC (Terms and conditions of determination of tariff according to Multi-year tariff principles) Regulations, 2008. In these Regulations of 2008, it was specified that the Commission shall follow the principles and methodologies specified by the Central Electricity Regulatory Commission (CERC) mentioned in the CERC (Terms and Conditions of Tariff) Regulations, 2004, in determination of tariff. The above Regulations of 2004 came into force from 01.04.2004 and remained in force for a period of 5 years i.e. up to 31.03.2009. Subsequent to these Regulations of 2004 the CERC has notified new Regulations namely CERC (Terms and Conditions of Tariff) Regulations, 2009 which have come into force from 01.04.2009 and shall remain in force for a period of 5 years from the date of commencement. Further, Forum of

Regulators (FOR) has constituted a working group on MYT framework for distribution licensee and the working group has made certain recommendations. Considering the (i) notification of above Regulations of 2009 of CERC wherein considerable changes have been made in reference to the earlier Regulations of 2004 by CERC and (ii) above recommendations of the FOR, this Commission has decided to make these new Regulations, which shall replace CSERC (Terms and conditions of determination of tariff according to Multi-year tariff principles) Regulations, 2008. , However, CSERC (Terms and Conditions of determination of Tariff) Regulations, 2006 of this Commission shall continue to remain in force for the purpose of filing of annual tariff petitions by the applicants.

"Chhattisgarh State Electricity Regulatory Commission (Terms and conditions of determination of tariff according to Multi-Year tariff Principles) Regulations, 2010"

In exercise of powers vested under Sub-sections (zd) and (zf) of Section 181 (2), read with Sections 61 and 62 of the Electricity Act 2003 (36 of 2003) the Chhattisgarh State Electricity Regulatory Commission hereby makes the following Regulations:

CHAPTER - 1

PRELIMINARY

1. **SHORT TITLE AND COMMENCEMENT:**

(i) These regulations may be called the Chhattisgarh State Electricity Regulatory Commission (Terms and Conditions of determination of tariff according to Multi-Year Tariff principles) Regulations, 2010.

(ii) These regulations shall be applicable for determination of tariff under Section 62 of the Act for the financial year 2010-11 and onwards, until these Regulations are superseded by new Regulations.

2. **SCOPE AND EXTENT OF APPLICATION:**

2.1 These Regulations shall apply to the following persons operating in the State of Chhattisgarh:

(a) The Chhattisgarh State Power Transmission Company Limited (CSPTCL) operating as a State Transmission Utility (STU) and a transmission licensee.

(b) All generating companies except generating companies owned or controlled by the Central Government and generating companies with a composite scheme of generation and sale in more than one state, which are subject to the jurisdiction of the CERC;

(c) intra-state transmission licensee(s); and

(d) Distribution licensee(s).

2.2 Notwithstanding the provisions of these Regulations, where tariff has been determined through a transparent process of bidding in accordance with the guidelines issued by the Central Government, the Commission shall adopt such tariff, as provided in Section 63 of the Act.

2.3 The norms of operation specified under these Regulations shall not preclude adoption of other norms of operation by the generating company / licensee(s) and such other norms shall be applicable for determination of tariff.

2.4 All proceedings under these Regulations shall be governed by the CSERC (Conduct of Business) Regulations, 2009 and amendment thereon.

3. **DEFINITIONS:** In these regulations, unless the context otherwise requires,-

3.1 **'Act'** means the Electricity Act, 2003 (36 of 2003) or any amendments made to the same or any succeeding enactment thereof;

3.2 **'Additional capitalization'** means the capital expenditure incurred or projected to be incurred after the date of commercial operation of the project and admitted by the Commission after prudence check, subject to provisions of Regulation 16;

3.3 "**Aggregate Revenue Requirement**" or "ARR" means the costs pertaining to the licensed and / or regulated business, which are permitted, in accordance with these regulations, to be recovered from the tariffs and charges determined by the Commission.

3.4 **"Applicant"** means a licensee or a generating company who has made an application for determination of tariff or an application for annual performance review in accordance with these Regulations and the Act and includes a licensee or generating company whose tariff and charges are to be determined by the Commission.

3.5 **'Auditor' means** an auditor appointed by the generating company or the licensee as the case may be, in accordance with the provisions of sections 224, and 619 of the Companies Act, 1956 (1 of 1956), or any other law for the time being in force;

3.6 **'Auxiliary Energy Consumption' or 'AUX'** in relation to a period in case of a generating station means the quantum of energy consumed by auxiliary equipments of the generating station, and transformer losses within the generating station, expressed as a

percentage of the sum of gross energy generated at the generator terminals of all the units of the generating station;

3.7 **"Beneficiary"**

(a) In relation to a ***generating station*** means the person buying power generated by such station on payment of annual fixed charges and / or energy charges; and

(b) in relation to ***transmission system*** means open access customers as defined in Chhattisgarh State Electricity Regulatory Commission (Intra-state Open Access in Chhattisgarh) Regulations, 2005, as amended from time to time, and includes distribution licensee(s) who have Transmission Service Agreement with the STU / Transmission Licensee.

3.8 **'Capital Cost'** means the capital cost as defined in Regulation 14;

3.9 **'Change in Law'** means occurrence of any of the following events:

(i) the enactment, bringing into effect, adoption, promulgation, amendment, modification or repeal of any law; or

(ii) change in interpretation of any law by a competent court, Tribunal or Indian Governmental Instrumentality which is the final authority under law for such interpretation; or

(iii). change by any competent statutory authority, in any consent, approval or license available or obtained for the project.

3.10 **'Commission'** means the Chhattisgarh State Electricity Regulatory Commission referred to in sub-section (1) of section 82 of the Act;

3.11 **"Control period"** means a multi-year period fixed by the Commission from time to time, typically 3 to 5 years, for which the principles for determination of revenue requirement and tariff will be fixed.

3.12 **'Cut-off Date'** means 31st March of the year closing after two years of the year of commercial operation of the project, and in case the project is declared under commercial operation in the last quarter of a year, the cut-off date shall be 31st March of the year closing after three years of the year of commercial operation;

3.13 **'Date of Commercial Operation' or 'COD'** means

3.13.1 in relation to a unit or block of the thermal generating station, the date

declared by the generating company after demonstrating the maximum continuous rating (MCR) or the installed capacity (IC) through a successful trial run after notice to the beneficiaries, from 00:00 hour of which scheduling process as per the Indian Electricity Grid Code (IEGC) / CG State Grid Code is fully implemented, and in relation to the generating station as a whole , the date of commercial operation of the last unit or the block of the generating station.

3.13.2 in relation to a unit of hydro generating station, the date declared by the generating company from 00:00 hour of which, after notice to the beneficiaries. Scheduling process in accordance with the CG State Grid Code is fully implemented, and in relation to the generating station as a whole, the date declared by the generating company after demonstrating peaking capability corresponding to installed capacity of the generating station through a successful trial run, after notice to the beneficiaries.

Note

1. In case the hydro generating station with pondage or storage is not able to demonstrate peaking capability corresponding to the installed capacity for the reasons of insufficient reservoir or pond level, the date of commercial operation of the last unit of the generating station shall be considered as the date of commercial operation of the generating station as a whole, provided that it will be mandatory for such hydro generating station to demonstrate peaking capability equivalent to installed capacity of the generating unit or the generating station as and when such reservoir /pond level is achieved.

2. In case of purely run-of-river hydro generating station if the unit or the generating station is declared under commercial operation during lean inflows period when the water is not sufficient for such demonstration, it shall be mandatory for such hydro generating station or unit to demonstrate peaking capability equivalent to installed capacity as and when sufficient inflow is available

3.13.3 in relation to the transmission system, the date declared by the STU / transmission licensee from 00:00 hour of which an element of the transmission system is in regular service after successful charging and trial operation:

Provided that the date shall be the first day of a calendar month and

transmission charge for the element shall be payable and its availability shall be accounted for, from that date:

Provided further that in case an element of the transmission system is ready for regular service but is prevented from providing such service for reasons not attributable to the transmission licensee, its suppliers or contractors, the Commission may approve the date of commercial operation prior to the element coming into regular service.

3.13.4 in relation to a distribution system, means the date of charging electric lines or substations to its declared voltage level. In cases where line(s)/substation(s) are declared ready for charging but the licensee is not able to charge for reasons not attributable to the licensee, 'date of operation' in respect of such line(s)/substation(s) shall be reckoned as seven days after the line(s)/substations(s) have been declared ready for charging.

3.14 **'Day'** means the 24 hour period starting at 00:00 hour;

3.15 **'Declared Capacity'** or **'DC'** in relation to a generating station means, the capability to deliver ex-bus electricity in MW declared by such generating station in relation to any time-block of the day or whole of the day, duly taking into account the availability of fuel or water, and subject to further qualification in the relevant regulation;

3.16 **'Design Energy' in case of hydro generating station,** means the quantum of energy which can be generated in a 90% dependable year with 95% installed capacity of the hydro generating station;

3.17 **"Distribution loss"** means the energy loss in the distribution system of a licensee;

3.18 **"ERC"** means expected revenue from tariff and charges that a licensee is permitted to recover;

3.19 **"Existing Generating Station"** means a generating station declared under commercial operation from a date prior to 01.04.2010;

3.20 **"Existing Project"** means the project declared under commercial operation from a date prior to 01.04.2010;

3.21 **"Gross Calorific Value"** or **'GCV'** in relation to a thermal generating station means the heat produced in Kcal by complete combustion of one kilogram of solid fuel or one litre liquid fuel, as the case may be;

3.22 `**Gross Station Heat Rate' or 'GHR'** means the heat energy input in Kcal required to generate one kWh of electrical energy at generator terminals of a thermal generating station;

3.23 **'Infirm Power'** means electricity injected into the grid prior to the commercial operation of a unit or block of the generating station;

3.24 **'Installed Capacity' or 'IC'** means the summation of the name plate capacities of all the units of the generating station or the capacity of the generating station (reckoned at the generator terminals), approved by the Commission from time to time;

'Intra-State Transmission Customer' means a person having a contractual right to use intra-State transmission system by paying transmission charges and other applicable charges ;3.26 **'Maximum Continuous Rating' or `MCR'** in relation to a unit of the thermal generating station means the maximum continuous output at the generator terminals, guaranteed by the manufacturer at rated parameters, means the maximum continuous output at the generator terminals, with water or steam injection (if applicable) and corrected to 50 Hz grid frequency and specified site conditions;

3.27 **'Normative Annual Plant Availability Factor' or 'NAPAF'** in relation to a generating station means the availability factor specified in Regulation 33.1 for thermal generating station and in Regulation 34A(i) for hydro generating station;

3.28 **'Operation and Maintenance Expenses' or 'O&M expenses'** means the expenditure on operation and maintenance of the project, or part thereof, and includes the expenditure on manpower, repairs, spares, consumables, insurance, and overheads;

3.29 `**Original Project Cost'** means the capital expenditure incurred by the generating company or the transmission licensee or the distribution licensee, as the case may be, within the original scope of the project up to the cut-off date as admitted by the Commission;

3.30 **'Plant Availability Factor (PAF)'** in relation to a generating station for any period means the average of the daily declared capacities (DCs) for all the days during that period expressed as a percentage of the installed capacity in MW reduced by the normative auxiliary energy consumption.

3.31 **'Project'** means a generating station and / or the transmission system or the distribution system, as the case may be, and in case of a hydro generating station includes all

components of generating facility such as dam, intake water conductor system, power generating station and generating units of the scheme, as apportioned to power generation;

3.32 **'Rated Voltage'** means the manufacturer's design voltage at which the transmission system is designed to operate and includes such lower voltage at which any transmission line is charged or for the time being charged, in consultation with intra-State transmission customers;

3.33 **"Regulated Business"** means the functions and activities which the licensee is required to undertake, in terms of the licence granted by the Commission or as a deemed licensee under the Act; and the generating company in terms of the provisions of the Act and the Regulations notified by the Commission;

3.34 **"Retail Supply Business"** means the business of sale of electricity by a distribution licensee to all categories of consumers within the area of supply, in accordance with the terms of the distribution licence;

3.35 **"Retail Supply Tariff"** is the rate charged by the distribution licensee for supply to consumer and includes charges for wheeling and retail supply services;

3.36 **'Run-of-River Generating Station'** means a hydro generating station which does not have upstream pondage;

3.37 **'Run-of-River Generating Station With Pondage'** means a hydro generating station with sufficient pondage for meeting the diurnal variation of power demand;

3.38 **'Scheduled Energy'** means the quantum of energy scheduled by the State Load Despatch Centre to be injected into the grid by a generating station over a day :

3.39 **'Scheduled Generation' or 'SG'** at any time or for any period or time-block means schedule of generation in MW or MWh ex-bus, given by the State Load Dispatch Centre;

3.40 **"State Load Dispatch Centre" or "SLDC"** means the centre established by the State Government for purposes of exercising the powers and discharging the functions under Section 31 of the Act;

3.41 **'Storage Type Generating Station'** means a hydro generating station associated with large storage capacity to enable variation of generation of electricity according to demand;

3.42 **Tariff Stabilization Fund'** shall mean the fund for which provision has already been made by the Commission in its Tariff Order for the year 2009-10 issued on dated 30.05.2009. The fund will be utilized for stabilizing the tariff and also for providing better services to the consumers. The Commission shall notify separate regulation for operation of the fund.

3.43 **'Transmission Service Agreement'** means the agreement, contract, memorandum of understanding. or any such covenant, entered into between the transmission licensee and the intra-State transmission customer for the operational phase of the transmission system.

3.44 **'Transmission System'** means a line or a group of lines with or without associated sub-station, and includes equipment associated with transmission lines and sub-stations:

3.45 **'Unit'** in relation to a thermal generating station means steam generator, turbine-generator and auxiliaries and in relation to a hydro generating station means turbine-generator and its auxiliaries:

3.46 **'Useful Life'** in relation to a unit of a generating station, transmission and distribution system from the COD shall mean the following, namely:-

(a)	Coal based thermal generating station	25 years
(b)	AC and DC sub-station	25 years
(c)	Hydro generating station	35 years
(d)	Transmission or distribution line	35 years

3.47 '**Wheeling**' means the operation whereby the distribution system and associated facilities of a transmission licensee or distribution licensee, as the case may be, are used by another person for the conveyance of electricity on payment of charges to be determined under Section 62 of the Act.

3.48 "**Wheeling Business**" means the business of operating and maintaining a distribution system for conveyance of electricity in the area of supply of the distribution licensee;

3.49 "**Year**" means the financial year ending on 31st March.

(a) "Current Year" means the year in which the statement of annual accounts or application for determination of tariff is filed;

(b) Ensuing Year" means the year next following the current year; and

(c) "Previous Year" means the year immediately preceding the current year.

The words and expressions used in these Regulations and not defined herein but defined in the Act shall have the meaning assigned to them under the Act and other Regulations notified by the Commission.

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CHAPTER - 2

MULTI-YEAR TARIFF FRAMEWORK, APPROACH AND PROCEDURE FOR TARIFF DETERMINATION AND COMPUTATION OF CAPITAL COST AND CAPITAL STRUCTURE.

4. MYT FRAMEWORK:

4.1 The Commission in specifying these Regulations is guided by the principles contained in Sections 61 and 62 of the Act, the National Electricity Policy and the Tariff Policy notified by the Central Government.

4.2 The multi-year tariff framework shall be based on the following for estimation of ARR and ERC

(a) A business plan submitted by the generating company / licensee and approved by the Commission for a period not less than the control period prior to the start of the control period;

(b) Forecast of the various financial and operational parameters of ARR, tariff and ERC to be filed by the generating company / licensee for each of the control period, based on the reasonable assumptions ;

(c) Trajectory for specific variables as may be stipulated by the Commission, where the performance of the generating company / licensee(s) is sought to be improved through incentives and disincentives;

(d) Determination of tariff for each financial year within the Control Period based on the approved ARR and performance targets at the start of Control Period, for generating company and transmission licensee/STU.

(e) Determination of tariff for each financial year based on the approved ARR and performance targets for the distribution licensee at the start of each financial year.

(f) Annual review of performance vis-a-vis the approved forecast and variations in performance of efficiency linked controllable items and other items;

(g) Mechanism for sharing approved gains or losses on account of efficiency linked controllable items;

(h) Mechanism for pass through of approved gains or losses on account of uncontrollable items;

(i) Revision in tariff may be done through annual tariff resetting process for each financial year within the control period, based on the results of the annual performance review and true up, as decided by the commission .

5. **MYT APPROACH:**

The MYT framework for estimation of the ARR shall be based on the following approach:

5.1 **Control Period:** The first control period under multi-year tariff framework may be a period of three (3) years or it can be extended up to 5 years and will commence from F.Y. 2010-11; and the subsequent control periods shall be a period of five (5) years or such other period as may be specified by the Commission from time to time.

5.2 **Base Year** The base year shall mean the financial year immediate preceding the initial year of the control period. For example, if the control period initiates from FY 2010-11, the base year will be FY 2009-10. The values of the base year of the control period will be determined based on the available audited / unaudited accounts of the last five years preceding the base year after prudence check.

5.3 **'Efficiency linked controllable items'**: The efficiency linked controllable items are as following :-

(1) Operation & Maintenance costs

(2) Transmission losses

(3) Distribution losses

(4) Collection efficiency

(5) The items for which norms including relaxed norms have specified in chapter 3 and 4 of these regulations.

5.4 **'Un-controllable Items'** - The uncontrollable items are as following –

(i) As per tariff policy 5.3 (h) (4) the un-controllable costs would include (but not limited to) fuel costs, costs on account of inflation, taxes and cess, variations in power purchase unit costs including on account of hydro-thermal mix in case of adverse natural events or any other items as may be considered by the Commission

(ii) Sales Mix,

(iii) Sales Quantum,

(iv) Any other item not covered in regulations 5.3 and 5.4 (i), (ii) and (iii).

5.5 **Targets:** Targets will be set by the Commission for the items that are 'controllable' as above. Besides, trajectory for specific variables may be stipulated by the Commission where the performance of the applicant is sought to be improved upon through incentives and disincentives.

5.6 **Profit-Sharing:** The applicant shall present a statement of gain and loss against each efficiency linked controllable item of the Aggregate Revenue Requirement separately.

5.7 For the purpose of sharing gains and losses with the consumers, only the aggregate net gains or losses will be considered.

5.8 There shall be no cap on the profits earned from operational performance, higher than the targets specified by the Commission.

5.9 The mechanism for sharing of aggregate net gain on account of better achievement in reference to the target set shall be as under:

(a) The one-third of the aggregate net gain on account of better achievement in reference with the target set in the tariff order for efficiency linked controllable items shall be passed on to the beneficiary / consumer(s) in the form of rebate in tariff.

(b) The one-third amount of gain on account of better achievement in reference with the target set in tariff order for efficiency linked controllable items shall be credited to the tariff stabilization fund.

(c) The one-third amount of gain on account of better achievement in reference with the target set in tariff order for efficiency linked controllable items shall be retained by the generating company or the licensee as the case may be and reasonable portion of this amount should be used for funding the incentive scheme(s) for the employees for the purpose of improving performance of the respective company. Prior approval for use of above gain will be taken by the respective company from the Commission before making any expenditure from such gain so earned.

(d) The aggregate net gains on account of uncontrollable items (as per tariff order) over such period shall be passed on to beneficiaries / consumers through the next ARR and /or credited to the tariff stabilization fund, as decided by the commission.

5.10 **The mechanism of sharing of aggregate net loss, if any, shall be as following :**

a) The aggregate net losses on account of under achievement in reference with the target set in tariff order for efficiency linked controllable items over such period shall be borne by the generating company or the licensee, as the case may be.

b) The aggregate net losses on account of uncontrollable items (as per tariff order) over such period shall be passed on to the beneficiaries / consumers through the next ARR and /or debited to the tariff stabilization fund, as decided by the commission.

6. BUSINESS PLAN:

6.1 The generating company and licensee shall file for approval of the Commission a business plan on 1st October of the year preceding the first year of the control period or any other date as may be specified by the Commission. The business plan should cover the entire control period, with details for each year of the control period.

6.2 The business plan shall contain *interalia* the capital investment plan, capitalization schedule, capital structure, financing plan for the proposed investment, sales/demand forecast, load forecast, power procurement plan, quality targets and proposed efficiencies including loss reduction, saving in operating cost and any other information as desired by the Commission.

6.3 The Commission shall scrutinize and approve the business plan after discussion with the stakeholder and public hearing and after taking into consideration the objections/ suggestions of the stakeholders and the public and any additional information provided by the applicant, if any.

6.4 The business plan shall be approved within a period of 60 days from the date of its filing in order to facilitate the applicant to file the MYT application within the stipulated period.

6.5 Based on the priorities or urgent requirements, the licensee or the generating company may request for the change in the approved business plan from the Commission, and shall execute such works only after getting prior approval from the commission.

7. TARIFF DETERMINATION:

7.1. Tariff in respect of a generating station may be determined for the whole of the generating station or a stage or unit or block of the generating station, and tariff for the transmission system may be determined for the whole of the transmission system or any part of the transmission system., . The retail supply tariff, wheeling charges and miscellaneous charges for the distribution licensee shall also be decided by the Commission for whole of the distribution system.

7.2. For the purpose of determination of tariff, the capital cost of the project may be broken up in stages and distinct units or blocks, transmission lines and sub-systems forming part of the project, if required:

Provided that where break-up of the capital cost of the project for different stages or units

or blocks and transmission lines or sub-stations is not available and in case of on-going projects, the common facilities shall be apportioned on the basis of the installed capacity of the units, line length and number of bays etc;

Provided further that in relation to multi-purpose hydro schemes, with irrigation, flood control and power components, the capital cost chargeable to the power component of the scheme only shall be considered for determination of tariff.

8. MYT FILING:

8.1. The generating company and transmission licensee/ STU shall file application for approval of ARR and tariff of each year of the entire control period. The distribution licensee shall file application for approval of ARR for each year of the entire control period and for the retail supply tariff of the ensuing year. These applications shall be filed not less than 120 days before the commencement of the first year of the control period. The applicant shall also submit a statement on compliance of directives issued by the Commission in its previous orders.

8.2. All the filings by any applicant should also be in conformity with the provisions of the CSERC (Licence) Regulations, 2004, its amendment(s) and the conditions of licence. The multi-year tariff filing shall be in such form and in such manner as may be prescribed by the Commission from time to time.

8.3. The application for tariff along with duly filled up formats and necessary justification will be treated as petition and shall be filed as per the procedure laid down in the CSERC (Conduct of Business) Regulations, 2009 as amended from time to time.

8.4. Every application for determination of tariff or for continuation of previously determined tariff shall be accompanied by a fee as specified in the CSERC (Fees and Charges) Regulations, 2009 as amended from time to time.

The Commission may seek clarification and additional information on the application and the applicant shall provide clarifications and additional information within the date stipulated by the Commission.

9. TRUING UP FOR THE PERIOD PRIOR TO COMMENCEMENT OF MYT ORDER:

9.1. Performance review and adjustment of variations in ARR and revenue from tariff and

charges of the generating company / licensee for the years prior to the first multi year tariff order passed by the Commission under these regulations, shall be based on the available un-audited / audited information after prudence check by the Commission.

9.2 The manner of sharing of losses and gains as a result of the true up exercise as above may be decided by the Commission. Such losses/gains may be passed on to Tariff Stabilization Fund and/or adjusted in ARR.

10. DISPOSAL OF MYT APPLICATION:

10.1 The Commission will process the MYT tariff filing of the Chhattisgarh State Power Distribution Co. Ltd. (CSPDCL), Chhattisgarh State Power Transmission Co. Ltd. (CSPTCL), Chhattisgarh State Power Generation Co. Ltd. (CSPGCL) / other applicants in accordance with these regulations and the Conduct of Business Regulations 2009 as amended from time to time.

10.2 The applicant shall publish the summary of the proposals, as approved by the Commission for publication, highlighting the salient features of the application that are of interest to various stakeholders, in at least three newspapers, two in Hindi and one in English, having wide circulation in the state and the area of the applicant.

10.3 Copies of the tariff application shall be made available for sale at the Commission's office and in such offices of the applicant as directed by the Commission. The document shall also be uploaded on the applicant's website in downloadable format for easy accessibility to all stakeholders.

10.4 The Commission shall hold proceedings on the ARR and ERC proposed by the applicant on the basis of prevailing and proposed tariff, and may hear such persons as the Commission considers appropriate, before deciding on such proposals.

10.5 Based on the applicant's filings, the Commission may accept the application, with such modifications and / or such conditions as may be deemed just and appropriate and pass orders within 120 days of the receipt of the application after considering all objections / suggestions / comments received from the stakeholders and the general public. The orders shall set *interalia* the targets for controllable items and state the approved Aggregate Revenue Requirement for applicant's regulated businesses.

10.6 The Commission shall determine tariff in accordance with the provisions and objectives of the Act; these Regulations; the Tariff policy and other prevalent policies or regulations, as the case may be.

10.7 All orders determining tariff shall indicate the period for which it shall be in force. The Commission may agree for continuation of existing tariff for a period beyond the period stipulated in the order, based on the application filed by the applicant, if the Commission concludes that the grounds for continuation are justified.

10.8 The Commission shall, within seven days of making the order, send a copy of the order to the appropriate State Government, the Central Electricity Authority and the concerned generating company / licensee.

10.9 The applicant shall publish the gist of the order including the approved tariffs, in at least three daily newspapers, two in Hindi and one in English, having wide circulation in its area of supply. Such tariff shall take effect only after minimum seven days from the date of such publication.

11. ANNUAL REVIEW OF PERFORMANCE AND TARIFF SETTING:

11.1 The generating company and licensee shall make an application for annual performance review, amendment in business plan, power procurement plan and tariff resetting not less than 120 days before the start of each financial year of the control period in the form as may be prescribed by the Commission. The licensee / generating company shall provide such information as may be asked for by the Commission with a view to assess the reasons and extent of any variation in the performance from the approved forecast and the need for tariff resetting. Normally, target set for the operating parameters in the tariff order shall not be changed annually.

11.2 The generating company / licensee may, as a result of additional information not previously known or available to him at the time of forecast under the MYT framework for the control period, apply for modification of the ARR, tariff and ERC for the remainder of the control period, as part of the annual performance review.

11.3 The Commission may, on account of availability of additional information not previously known or available to it at the time of approval of the forecast under the MYT framework for the control period, either suo motu or on application made by any interested party,

modify the approved forecast of ARR and ERC for the remainder of the control period as part of the annual performance review.

11.4 In the annual performance review application, the generating company / licensee shall submit information for the purpose of calculating expected revenue and expenditure along with information on financial and operational performance for the previous year, current year and the ensuing year. The information for the previous year should be based on audited accounts however in case audited accounts for the previous year are not available, then the information may be based on unaudited accounts.

11.5 The Commission shall review an application made under regulation 11.1 and / or regulation 11.2 above in the same manner as the original application for determination of ARR and ERC and upon completion of such review, either approve the proposed modification with such changes as it deems appropriate, or reject the application for reasons to be recorded in writing.

11.6 The scope of the annual performance review shall be a comparison of the performance of the licensee with the approved forecast of ARR and ERC along with the performance targets. Upon completion of the annual performance review, the Commission shall pass an order recording:

(a) The approved forecast of ARR and ERC for such financial year including approved modifications, if any.

(b) The approved aggregate gain or loss to the licensee on account of uncontrollable items and passing through of such gains or losses as envisaged in regulations 5.9 and 5.10.

(c) The approved aggregate gain or loss to the licensee on account of efficiency linked controllable items and sharing of such gains or losses as envisaged in regulations 5.9 and 5.10.

(d) Truing up of ARR items of previous year(s), if any.

(e) The approved modifications, if any, to the forecast for the remainder period of the control period.

12. REVIEW AT THE END OF THE CONTROL PERIOD

12.1 At the end of the control period, the Commission shall review the achievement of objectives and implementation of the principles of MYT laid- down in these Regulations.

To meet the objects of the Act, the National Electricity Policy and Tariff Policy, the Commission may revise the principles of MYT for the second and subsequent control period.

12.2 The end of the first control period may be the beginning of the second control period or as decided by the Commission. The Commission shall analyse the performance with respect to the targets set out at the beginning of the control period and shall determine the base value for the next control period, based on actual performance achieved, expected improvement and other relevant factors.

13. TRUE UP:

13.1 Truing up of the ARR and revenue earned from tariff and charges shall be done in the ensuing year along with the annual performance review of the current year.

13.2 The truing up done on the basis of un-audited / provisional account shall be subject to further final truing up, as soon as the audited account is available.

13.3 The net financial impact of true-ups shall be accounted for as per the provisions of regulation 5.9 and regulation 5.10, considering the factors like inflation, natural calamity etc. by the Commission.

14. CAPITAL COST:

14.1 Capital cost for a project shall include:

(a) the expenditure incurred or projected to be incurred, including interest during construction and financing charges, any gain or loss on account of foreign exchange risk variation during construction on the loan - (i) being equal to 70% of the funds deployed, in the event of the actual equity being 30% or in excess of 30% of the funds deployed, by treating the excess equity as normative loan, or (ii) being equal to the actual amount of loan in the event, of the actual equity less than 30% of the funds deployed, up to the date of commercial operation of the project, as admitted by the Commission, after prudence check;

(b) capitalized initial spares subject to the ceiling rates specified in regulation 15; and

(c) additional capital expenditure determined under regulation 16:

Provided that the assets forming part of the project, but not in use shall be taken out of the capital cost.

14.2 The capital cost admitted by the Commission after prudence check shall form the basis for determination of tariff:

Provided that in case of the thermal generating station and the transmission system, prudence check of capital cost may be carried out based on the benchmark norms to be specified by the Commission from time to time:

Provided further that in cases where benchmark norms have not been specified, prudence check may include scrutiny of the reasonableness of the capital expenditure, financing plan, interest during construction, use of efficient technology, cost over-run and time over-run, and such other matters as may be considered appropriate by the Commission for determination of tariff:

Provided also that the Commission may issue guidelines for vetting of capital cost of hydro-electric projects by independent agency or expert and in that event the capital cost as vetted by such agency or expert may be considered by the Commission while determining the tariff for the hydro generating station:

Provided also that in case the site of a hydro generating station is awarded to a developer (not being a State controlled or owned company), by a State Government by following a two stage transparent process of bidding, any expenditure incurred or committed to be incurred by the project developer for getting the project site allotted shall not be included in the capital cost:

Provided also that the capital cost in case of such hydro generating station shall include:

(a) cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with R&R package as approved; and

(b) cost of the developer's 10% contribution towards Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) project in the affected area:

Provided also that where the power purchase agreement entered into between the generating company and the beneficiaries and the transmission service agreement entered into between the transmission licensee and the transmission customer, as the case may be, provide for ceiling of actual expenditure, the capital expenditure admitted by the Commission shall take into consideration such ceiling for determination of tariff.

15. INITIAL SPARES:

Initial spares shall be capitalized as a percentage of the original project cost, subject to following ceiling norms:

(i)	Coal-based/lignite-fired thermal generating stations	-	2.5%
(ii)	Hydro generating stations	-	1.5%
(iii)	Transmission or distribution system		
	(a) Transmission or distribution line	-	0.75%
	(b) Transmission or distribution Sub-station	-	2.5%
	(c) Series / Parallel Compensation devices and HVDC Station	-	3.5%

Provided that where the benchmark norms for initial spares have been published as part of the benchmark norms for capital cost under first proviso to regulation 14.2, such norms shall apply to the exclusion of the norms specified herein.

16. ADDITIONAL CAPITALIZATION:

16.1 The capital expenditure incurred or projected to be incurred, on the following counts within the original scope of work, after the date of commercial operation and up to the cut-off date may be admitted by the Commission, subject to prudence check:

(i) Undischarged liabilities;

(ii) Works deferred for execution;

(iii) Procurement of initial capital spares within the original scope of work, subject to the provisions of regulation 15;

(iv) Liabilities to meet award of arbitration or for compliance of the order or decree of a court; and

(v) Change in law:

Provided that the details of works included in the original scope of work along with estimates of expenditure, undischarged liabilities and the works deferred for execution shall be submitted along with the application for determination of tariff.

16.2 The capital expenditure incurred on the following counts after the cut-off date may, in its discretion, be admitted by the Commission, subject to prudence check:

(i) Liabilities to meet award of arbitration or for compliance of the order or decree of a court;

(ii) Change in law;

(iii) Deferred works relating to ash pond or ash handling system in the original scope of work;

(iv) In case of hydro generating stations, any expenditure which has become necessary on account of damage caused by natural calamities (but not due to flooding of power house attributable to the negligence of the generating company) including due to geological reasons after adjusting for proceeds from any insurance scheme, and expenditure incurred due to any additional work which has become necessary for successful and efficient plant operation; and

(v) In case of transmission /distribution system any additional expenditure on items such as relays, control and instrumentation, computer system, power line carrier communication, DC batteries, replacement of switchyard equipment due to increase of fault level, emergency restoration system, insulators cleaning infrastructure, replacement of damaged equipment not covered by insurance and any other expenditure which has become necessary for successful and efficient operation of transmission / distribution system:

Provided that in respect sub-clauses (iv) and (v) above, any expenditure on acquiring the minor items or the assets like tools and tackles, furniture, air-conditioners, voltage stabilizers, refrigerators, coolers, fans, washing machines, heat convectors, mattresses, carpets etc. brought after the cut-off date shall not be considered for additional capitalization for determination of tariff FY 2010-11.

17. RENOVATION AND MODERNIZATION:

17.1 The generating company or the transmission licensee / STU or the distribution licensee, as the case may be, for meeting the expenditure on renovation and modernization (R&M) for the purpose of extension of life beyond the useful life of the generating station or a unit thereof or the transmission system or the distribution system, shall make an application before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, record of consultation with beneficiaries and any other information considered to be relevant by the generating company or the transmission licensee or the distribution licensee:

Provided that in case of coal-based thermal generating station, the generating company, may, in its discretion, avail of a 'special allowance' in accordance with the norms specified in the regulation 17.4, as compensation for meeting the requirement of expenses including renovation and modernization beyond the useful life of the generating station or a unit thereof, and in such an event revision of the capital cost shall not be considered and the applicable operational norms shall not be relaxed but the special allowance shall be included in the annual fixed cost:

Provided also that such option shall not be available for a generating station or unit for which renovation and modernization has been undertaken and the expenditure has been admitted by the Commission before commencement of these regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms.

17.2 Where the generating company or the transmission licensee or the distribution licensee, as the case may be, makes an application for approval of its proposal for renovation and modernization, the approval shall be granted after due consideration of reasonableness of the cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, and such other factors as may be considered relevant by the Commission.

17.3 Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on the estimates of renovation and modernization expenditure and life extension, and after deducting the accumulated depreciation already recovered from the original project cost, shall form the basis for determination of tariff.

17.4 A generating company on opting for the alternative in the first proviso to the regulation 17.1 of this regulation, for a coal-based thermal generating station, shall be allowed special allowance @ Rs. 5.286 lakh/MW/year in 2010-11 and thereafter escalated @ 5.72% every year during the tariff period, unit-wise from the next financial year from the respective date of the completion of useful life with reference to the date of commercial operation of the respective unit of generating station:

Provided, that in respect of a unit in commercial operation for more than 25 years as on 01.04.2010 this allowance shall be admissible from the year 2010-11.

18. SALE OF INFIRM POWER: Supply of infirm power shall be accounted as Unscheduled Interchange (UI) and paid for from the regional or State UI pool account at the applicable frequency-linked UI rate:

Provided that any revenue earned by the generating company from sale of infirm power after accounting for the fuel expenses shall be applied for reduction in capital cost:

19. DEBT-EQUITY RATIO:

19.1 For a project declared under commercial operation on or after 01.04.2010, if the equity capital actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan:

Provided that where equity capital actually deployed is equal or less than 30% of the capital cost, the actual equity shall be considered for determination of tariff:

Provided, further that the equity invested in foreign currency shall be designated in Indian rupees on the date of each investment.

Explanation.- The premium, if any, raised by the generating company or the transmission licensee or the distribution licensee, as the case may be, while issuing share capital and investment of internal resources created out of its free reserve, for the funding of the project, shall be reckoned as paid up capital for the purpose of computing return on equity, provided such premium amount and internal resources are actually utilized for meeting the capital expenditure of the generating station or the transmission system or the distribution system .

19.2 In case of the generating station and the transmission system declared under commercial operation prior to 01.04.2010, debt-equity ratio allowed by the Commission for determination of tariff for the period ending 31.3.2010 shall be considered.

19.3 Any expenditure incurred or projected to be incurred on or after 01.04.2010 as may be admitted by the Commission as additional capital expenditure for determination of tariff. and renovation and modernization expenditure for life extension shall be serviced in the manner specified in regulation 19.1 of these Regulations. .

19.4 In case of transmission licensee or distribution licensee the cost of project and accordingly debt equity ratio may be calculated considering the whole network of transmission or distribution system of the licensee, as the case may be, in place of individual line or project.

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CHAPTER – 3

COMPUTATION OF TARIFF OF GENERATING PLANTS AND TRANSMISSION SYSTEMS

20. COMPONENTS OF TARIFF:

20.1 The tariff for supply of electricity from a thermal generating station shall comprise two parts, namely, capacity charge (for recovery of annual fixed cost consisting of the components specified to in regulation 21) and energy charge (for recovery of primary fuel cost).

20.2 The tariff for supply of electricity from a hydro generating station shall comprise capacity charge and energy charge to be derived in the manner specified in regulation 29, for recovery of annual fixed cost (consisting of the components referred to in regulation 21) through the two charges.

20.3 The tariff for transmission of electricity on intra-State transmission system shall comprise transmission charge for recovery of annual fixed cost consisting of the components specified in Regulation 21.

21. ANNUAL FIXED COST: The annual fixed cost (AFC) of a generating station or a transmission system shall consist of the following components –

(a) Return on equity;

(b) Interest on loan capital;

(c) Depreciation;

(d) Interest on working capital;

(e) Operation and maintenance expenses;

(f) Cost of secondary fuel oil (for coal-based generating stations only);

(g) Special allowance in lieu of R&M or separate compensation allowance, wherever applicable.

NOTE: Non-Tariff Income as specified in the regulation 65, shall be subtracted from the sum of above (a to g) to arrive at AFC

22. RETURN ON EQUITY:

22.1 Return on Equity shall be computed in rupee terms on the equity base determined in accordance with Regulations 19..

22.2 Return on equity shall be computed on pre-tax basis at the base rate of maximum 15.5 % to be grossed up as per regulation 22.3 of these regulations:

Provided that in case of projects commissioned on or after 1st April, 2010, an additional return of 0.5% shall be allowed if such projects are completed within the timeline specified in **Appendix-I**:

Provided, further that the additional return of 0.5% shall not be admissible if the project is not completed within the timeline specified above for reasons whatsoever.

22.3 The rate of return on equity shall be computed by grossing up the base rate with the normal tax rate for the relevant year applicable to the concerned generating company or the transmission licensee/STU, as the case may be;

Provided that return on equity with respect to the actual tax rate applicable to the generating company or the transmission licensee/STU, as the case may be, in line with the provisions of the relevant Finance Acts of the respective year during the tariff period shall be trued up separately for each year of the tariff period along with the tariff petition filed for the next tariff period.

22.4 Rate of return on equity shall be rounded off to three decimal points and be computed as per the formula given below:

Rate of pre-tax return on equity = Base rate / (1-t)

Where, t is the applicable tax rate in accordance with regulation 22.3 of these regulations.

Illustration-

(i) In case of the generating company or the transmission licensee paying Minimum Alternate Tax (MAT) @ 11.33% including surcharge and cess:

Rate of return on equity = 15.5 / (1-0.1133) = 17.481%

(ii) In case of generating company or the transmission licensee paying normal corporate tax @ 33.99% including surcharge and cess: Rate of return on equity

= 15.5 /(1-0.3399) = 23.481%

23. INTEREST ON LOAN CAPITAL:

23.1 The loans arrived at in the manner indicated in Regulation 19 shall be considered as gross normative loan for calculation of interest on loan.

23.2 The normative loan outstanding as on 01.04.2010 shall be worked out by deducting the cumulative repayment as admitted by the Commission up to 31.3.2010 from the gross normative loan.

23.3 The repayment for the year of the tariff period shall be deemed to be equal to the depreciation allowed for that year.

23.4 Notwithstanding any moratorium period availed by the generating company or the transmission licensee/STU, as the case may be the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the annual depreciation allowed.

23.5 The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the project.:

Provided that if there is no actual loan for a particular year but normative loan is still outstanding, the last available weighted average rate of interest shall be considered:

Provided further that if the generating station or the transmission system, as the case may be, does not have actual loan, then the weighted average rate of interest of the generating company or the transmission licensee as a whole shall be considered.

23.6 The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest.

23.7 The generating company or the transmission licensee/STU, as the case may be, shall make every effort to re-finance the loan as long as it results in net savings on interest and in that event the costs associated with such re-financing shall be borne by the beneficiaries and the net savings shall be shared between the beneficiaries and the generating company or the transmission licensee, as the case may be, in the ratio of 50:50.

23.8 The changes to the terms and conditions of the loans shall be reflected from the date of such re-financing.

23.9 In case of dispute, any of the parties may make an application in accordance with the Chhattisgarh State Electricity Regulatory Commission (Conduct of Business)Regulations,

2009, as amended from time to time, including statutory re-enactment thereof for settlement of the dispute:

Provided, that the beneficiary or the transmission customers shall not withhold any payment on account of the interest claimed by the generating company or the transmission licensee during the pendency of any dispute arising out of re-financing of loan.

24. DEPRECIATION:

24.1 The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission.

24.2 The salvage value of the asset shall be considered as 10% and depreciation shall be allowed up to maximum of 90% of the capital cost of the asset.

Provided that in case of hydro generating stations, the salvage value shall be as provided in the agreement signed by the developers with the State Government for creation of the site:

Provided further that the capital cost of the assets of the hydro generating station for the purpose of computation of depreciable value shall correspond to the percentage of sale of electricity under long-term power purchase agreement at regulated tariff.

24.3 Land other then the land held under lease and the land for reservoir in case of hydro generating station shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing depreciable value of the asset.

24.4 Depreciation shall be calculated annually based on Straight Line Method and at rates specified in **Appendix-II** to these regulations for the assets of the generating station and transmission system:

Provided that, the remaining depreciable value as on 31st March of the year closing after a period of 12 years from date of commercial operation shall be spread over the balance useful life of the assets.

24.5 In case of the existing projects, the balance depreciable value as on 1.4.2010 shall be worked out by deducting the cumulative depreciation as admitted by the Commission upto 31.3.2010 from the gross depreciable value of the assets.

24.6 Depreciation shall be chargeable from the first year of commercial operation. In case of commercial operation of the asset for part of the year, depreciation shall be charged on *prorata* basis.

25. INTEREST ON WORKING CAPITAL:

25.1 The working capital shall cover :

(a) **In case of coal-based thermal generating stations:**

(i) Cost of coal, if applicable, for 1½ months for pit-head generating stations and two months for non-pit-head generating stations, for generation corresponding to the normative annual plant availability factor;

(ii) Cost of secondary fuel oil for two months for generation corresponding to the normative annual plant availability factor, and in case of use of more than one secondary fuel oil, cost of fuel oil stock for the main secondary fuel oil.

(iii) Maintenance spares @ 20% of operation and maintenance expenses specified in regulation 26.

(iv) Receivables equivalent to two months of capacity charges and energy charges for sale of electricity calculated on the normative annual plant availability factor, and

(v) Operation and maintenance expenses for one month.

(b) **In case of hydro generating station and transmission system and distribution system**

(i) Receivables equivalent to two months of fixed cost.

(ii) Maintenance spares @ 15% of operation and maintenance expenses specified in regulation 26;

(iii) Operation and maintenance expenses for one month.

25.2 The cost of fuel in cases covered under sub-clauses (a) of regulation 25.1 shall be based on the landed cost incurred taking into account normative transit and handling losses by the generating company and gross calorific value of the fuel as per latest available actual data for the three months and no fuel price escalation shall be provided during the tariff period.

25.3 Rate of interest on working capital shall be on normative basis and shall be equal to the latest available short-term Prime Lending Rate of State Bank of India in which the generating station or a unit thereof or the transmission system, as the case may be, is declared under commercial operation.

25.4 Interest on working capital shall be payable on normative basis notwithstanding that the generating company or the transmission licensee or the distribution licensee has not taken loan for working capital from any outside agency.

26. OPERATION AND MAINTENANCE EXPENSES:

(A) Normative operation and maintenance expenses for generating stations:-

(1) Operation and Maintenance (O&M) expenses shall mean the total of all expenditure under the following heads:

(a) Employee costs;

(b) Repairs and Maintenance (R & M) expenses; and

(c) Administrative and General (A& G) costs.

(2) The generating company in its filings shall submit the O&M expenses in above heads separately on the basis of available audited / un audited accounts for the previous five years preceding the base year and also for the base year. The O&M expenses for the base year will be used for projecting the expenses for each year of the control period.

(3) The O&M expenses, for the units / stations coming into commercial operation after 01.04.2005, shall be in accordance with the norms specified in CERC (Terms and Conditions of tariff) Regulations, 2009 as amended from time to time.

(B) Normative operation and maintenance expenses for Transmission units:-

(i) Norms for operation and maintenance expenses shall be as under:

	2010-11	2011-12	2012-13	2013-14
Norms for sub-station (Rs Lakh per bay)				
765 kV	77.56	81.99	86.68	91.64
400 kV	55.40	58.57	61.92	65.46
220 kV	38.78	41.00	43.34	45.82
132 kV	27.70	29.28	30.96	32.73
66 KV	19.39	20.50	21.67	22.91
33 KV	13.57	14.35	15.17	16.04
11 KV	9.50	10.04	10.62	11.23

Norms for AC and HVDC lines (Rs Lakh per km)				
Single Circuit (Bundled conductor with four or more sub-conductors)	0.568	0.600	0.635	0.671
Single Circuit (Twin & Triple Conductor)	0.378	0.400	0.423	0.447
Single Circuit (Single Conductor)	0.189	0.200	0.212	0.224
Double Circuit (Bundled conductor with four or more sub-conductors)	0.994	1.051	1.111	1.174
Double Circuit (Twin & Triple Conductor)	0.663	0.701	0.741	0.783
Double Circuit (Single Conductor)	0.284	0.301	0.318	0.336
Norm for HVDC Stations				
HVDC Back-to-back stations (Rs lakh per 500m MW)	468	495	523	553

(ii) The total allowable operation and maintenance expenses for the transmission system shall be calculated by multiplying the number of bays and kms of line length with the applicable norms for the operation and maintenance expenses per bay and per km respectively.

27. EXPENSES ON SECONDARY FUEL OIL CONSUMPTION FOR COAL-BASED GENERATING STATION:

27.1 Expenses on secondary fuel oil in Rupees shall be computed corresponding to normative secondary fuel oil consumption (SFC) specified in Regulation 33.3, in accordance with the following formula:

$$= SFC \times LPSF_i \times NAPAF \times 24 \times NDY \times IC \times 10$$

Where,

SFC – Normative Specific Fuel Oil consumption in ml/kWh

$LPSF_i$ – Weighted Average Landed Price of Secondary Fuel in Rs./ml considered initially

NAPAF – Normative Annual Plant Availability Factor in percentage

NDY – Number of days in a year

IC - Installed Capacity in MW.

27.2 Initially, the landed cost incurred by the generating company on secondary fuel oil shall be taken based on actuals of the weighted average price of the three preceding months and in the absence of landed costs for the three preceding months, latest procurement price for the generating station, before the start of the year.

The secondary fuel oil expenses shall be subject to fuel price adjustment at the end of the

each year of tariff period as per following formula:

$SFC \times NAPAF \times 24 \times NDY \times IC \times 10 \times (LPSF_y - LPSF_i)$

Where,

$LPSF_y$ =The weighted average landed price of secondary fuel oil for the year in Rs. /ml

28. COMPUTATION AND PAYMENT OF CAPACITY CHARGE AND ENERGY CHARGE FOR THERMAL GENERATING STATIONS:

28.1 The fixed cost of a thermal generating station shall be computed on annual basis, based on norms including relaxed norms specified under these regulations, and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share / allocation in the capacity of the generating station.

28.2 The capacity charge (inclusive of incentive) payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae :

(a) Generating stations in commercial operation for less than ten (10) years on 1st April of the financial year : $AFC \times (NDM / NDY) \times (0.5 + 0.5 \times PAFM / NAPAF)$ (in Rupees);

Provided that in case the plant availability factor achieved during a financial year (PAFY) is less than 70%, the total capacity charge for the year shall be restricted to

$AFC \times (0.5 + 35 / NAPAF) \times (PAFY / 70)$ (in Rupees).

(b) For generating stations in commercial operation for ten (10) years or more on 1st April of the year: $AFC \times (NDM / NDY) \times (PAFM / NAPAF)$ (in Rupees).

Where,

AFC = Annual fixed cost specified for the year, in Rupees.

NAPAF = Normative annual plant availability factor in percentage

NDM = Number of days in the month

NDY = Number of days in the year

PAFM = Plant availability factor achieved during the month, in percent:

PAFY = Plant availability factor achieved during the year, in percent

28.3 The PAFM and PAFY shall be computed in accordance with the following formula:

$$\text{PAFM or PAFY} = 10000 \times \sum_{i=1}^{N} DC_i \; / \; \{ N \times IC \times (100 - AUX) \} \; \%$$

Where,

AUX = Normative auxiliary energy consumption in percentage.

DC_i = Average declared capacity (in ex-bus MW), subject to clause below, for the i^{th} day of the period i.e. the month or the year as the case may be, as certified by the State load dispatch centre after the day is over.

IC = Installed Capacity (in MW) of the generating station

N = Number of days during the period i.e. the month or the year as the case may be.

Note :

DC_i and IC shall exclude the capacity of generating units not declared under commercial operation. In case of a change in IC during the concerned period, its average value shall be taken.

28.4 In case of fuel shortage in a thermal generating station, the generating company may propose to deliver a higher MW during peak-load hours by saving fuel during off-peak hours. The State Load Despatch Centre may then specify a pragmatic day-ahead schedule for the generating station to optimally utilize its MW and energy capability, in consultation with the beneficiaries. DCi in such an event shall be taken to be equal to the maximum peak-hour ex- power plant MW schedule specified by the State Load Despatch Centre for that day.

28.5 The energy charge shall cover the primary fuel cost, and shall be payable by every beneficiary for the total energy scheduled to be supplied to such beneficiary during the calendar month on ex-power plant basis, at the energy charge rate of the month (with fuel price adjustment). Total Energy charge payable to the generating company for a month shall be:

(Energy charge rate in Rs./kWh) x {Scheduled energy (ex-bus) for the month in kWh.}

Energy charge rate (ECR) in Rupees per kWh on ex-power plant basis shall be determined to three decimal places in accordance with the following formulae **for coal based stations**:

ECR = { (GHR – SFC x CVSF) x LPPF / CVPF } x 100 / (100 – AUX)

Where,

AUX	=	Normative auxiliary energy consumption in percentage.
CVPF	=	Gross calorific value of primary fuel as fired, in kCal per kg, per litre or per standard cubic meter, as applicable.
CVSF	=	Calorific value of secondary fuel, in kCal per ml.
ECR	=	Energy charge rate, in Rupees per kWh sent out.
GHR	=	Gross station heat rate, in kCal per kWh.
LPPF	=	Weighted average landed price of primary fuel, in Rupees per kg, per litre or per standard cubic meter, as applicable, during the month.
SFC	=	Specific fuel oil consumption, in ml per kWh.

28.6 The landed cost of fuel for the month shall include price of fuel corresponding to the grade and quality of fuel inclusive of royalty, taxes and duties as applicable. transportation cost by conveyer / rail / road or any other means, and, for the purpose of computation of energy charge, and in case of coal shall be arrived at after considering normative transit, stacking and handling losses as percentage of the quantity of coal dispatched by the coal supply company during the month as given below :

(a) Pithead generating stations: 0.3%

(b) Non-pithead generating stations 0.8%

	2010-11	2011-12	2012-13
(c) Korba East TPS Complex	1.25%	1.20%	1.15%
(d) DSPM Thermal Power Station	0.80%	0.75%	0.70%

29. COMPUTATION AND PAYMENT OF CAPACITY CHARGE AND ENERGY CHARGE FOR HYDRO GENERATING STATIONS:

29.1 The fixed cost of a hydro generating station shall be computed on annual basis, based on norms specified under these regulations, and recovered on monthly basis under capacity

charge (inclusive of incentive) and energy charge, which shall be payable by the beneficiaries in proportion to their respective allocation in the saleable capacity of the generating station, that is to say, in the capacity excluding the free power to the home State:

Provided that during the period between the date of commercial operation of the first unit of the generating station and the date of commercial operation of the generating station, the annual fixed cost shall provisionally be worked out based on the latest estimate of the completion cost for the generating station, for the purpose of determining the capacity charge and energy charge payment during such period.

29.2 The capacity charge (inclusive of incentive) payable to a hydro generating station for a calendar month shall be

AFC x 0.5 x NDM / NDY x (PAFM / NAPAF) (in Rupees) Where,

AFC	=	Annual fixed cost specified for the year, in Rupees
NAPAF	=	Normative plant availability factor in percentage
NDM	=	Number of days in the month
NDY	=	Number of days in the year
PAFM	=	Plant availability factor achieved during the month, in percentage

29.3. The PAFM shall be computed in accordance with the following formula :

$$PAFM = 10000 \times \sum_{i=1}^{N} DC_i / \{ N \times IC \times (100 - AUX) \} \%$$

Where,

AUX	=	Normative auxiliary energy consumption in percentage
DC_i	=	Declared capacity (in ex-bus MW) for the i^{th} day of the month which the station can deliver for at least three (3) hours, as certified by the nodal load dispatch centre after the day is over.
IC	=	Installed capacity (in MW) of the complete generating station
N	=	Number of days in the month

29.4 The energy charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary, excluding free energy, if any, during the calendar month, on ex power plant basis, at the computed energy charge rate. Total Energy charge payable to the generating company for a month shall be :

(Energy charge rate in Rs. / kWh) x {Scheduled energy (ex-bus) for the month in kWh} x (100 – FEHS) / 100.

29.5 Energy charge rate (ECR) in Rupees per kWh on ex-power plant basis, for a hydro generating station, shall be determined up to three decimal places. based on the following formula, subject to the provisions of regulation 29.7 :

ECR = AFC x 0.5 x 10 / { DE x (100 – AUX) x (100 – FEHS)} Where,

DE = Annual design energy specified for the hydro generating station, in MWh, subject to the provision in regulation 29.6 below.

FEHS = Free energy for home State, in per cent as decided by the Government of Chhattisgarh wherever applicable.

29.6 In case actual total energy generated by a hydro generating station during a year is less than the design energy for reasons beyond the control of the generating company, the following treatment shall be applied on a rolling basis:

(i) in case the energy shortfall occurs within ten years from the date of commercial operation of a generating station, the ECR for the year following the year of energy shortfall shall be computed based on the formula specified in regulation 29.5 with the modification that the DE for the year shall be considered as equal to the actual energy generated during the year of the shortfall, till the energy charge shortfall of the previous year has been made up, after which normal ECR shall be applicable;

(ii) in case the energy shortfall occurs after ten years from the date of commercial operation of a generating station, the following shall apply:

Suppose the specified annual design energy for the station is DE MWh, and the actual energy generated during the concerned (first) and the following (second) financial years is A1 and A2 MWh respectively, A1 being less than DE. Then the design energy to be considered in the formula in regulation 29.5 of this

Regulation for calculating the ECR for the third financial year shall be moderated as (A1 + A2 – DE) MWh, subject to a maximum of DE MWh and a minimum of A1 MWh.

(iii) Actual energy generated (e.g. A1, A2) shall be arrived at by multiplying the net metered energy sent out from the station by 100 / (100 – AUX).

29.7 In case the energy charge rate (ECR) for a hydro generating station, as computed in regulation 29.5 above, exceeds eighty paise per kWh, and the actual saleable energy in a year exceeds

{DE x (100 – AUX) x (100 – FEHS) / 10000 } MWh, the Energy charge for the energy in excess of the above shall be billed at eighty paise per kWh only:

Provided that in a year following a year in which total energy generated was less than the design energy for reasons beyond the control of the generating company, the energy charge rate shall be reduced to eighty paise per kWh after the energy charge shortfall of the previous year has been made up.

29.8 The State Load Despatch Centre shall finalize the schedules for the hydro generating stations, in consultation with the beneficiaries, for optimal utilization of all the energy declared to be available, which shall be scheduled for all beneficiaries in proportion to their respective allocations in the generating station.

30. COMPUTATION AND PAYMENT OF TRANSMISSION CHARGE FOR INTRA-STATE TRANSMISSION SYSTEM:

30.1 The fixed cost of the transmission system shall be computed on annual basis, in accordance with norms contained in these regulations, aggregated as appropriate, and recovered on monthly basis as transmission charge from the users.

30.2 The transmission charge (inclusive of incentive) payable for a calendar month for a transmission system or part thereof shall be

AFC x (NDM / NDY) x (TAFM / NATAF) Where,

AFC	=	Annual fixed cost specified for the year, in Rupees
NATAF	=	Normative annual transmission availability factor, in percent
NDM	=	Number of days in the month
NDY	=	Number of days in the year
TAFM	=	Transmission system availability factor for the month, in Percent computed in accordance with Appendix III –

30.3 The transmission charges shall be calculated separately for part of the transmission system having differing NATAF, and aggregated thereafter, according to their sharing by the beneficiaries.

30.4 The transmission licensee shall raise the bill for the transmission charge (inclusive of incentive) for a month based on its estimate of TAFM. Adjustments, if any, shall be made on the basis of the TAFM to be certified by the SLDC within 30 days from the last day of the relevant month.

31. UNSCHEDULED INTERCHANGE (UI) CHARGES:

31.1 All variations between actual net injection and scheduled net injection for the generating stations, and all variations between actual net drawal and scheduled net drawal for the beneficiaries shall be treated as their respective Unscheduled Interchanges (UI), charges as specified by the CERC from time to time including the price cap for the thermal generating stations.

31.2 Actual net unscheduled interchange of every intra-State entity shall be metered on its periphery through special energy meters (SEMs) installed by the Chhattisgarh State Transmission Utility (STU), and computed in MWh for each 15-minute time block by the State Load Dispatch Centre.

31.3 Any other matter related to the UI charges applicability, etc., shall be dealt as per CERC (UI) Regulations as amended from time to time, till such regulations are specified by the Commission.

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CHAPsTER - 4

NORMS OF OPERATION

32. (1) . Recovery of capacity charge, energy charge, transmission charge and incentive by the generating company and the transmission licensee shall be based on the achievement of the operational norms specified in this Chapter.

(2) The Commission may on its own may revise the operating norms / relaxed norms specified in this Chapter in respect of any of the generating stations.

Norms of operation for thermal generating station

33. The norms of operation as given hereunder shall apply to thermal generating station:

33.1 **Normative Annual Plant Availability Factor (NAPAF)**

a. All thermal generating stations except those covered under clause (b) and (c)- 85%

b. Hasdeo Thermal Power Station Korba (4x 210 MW) 82%

c. Korba East TPS Complex (4 x 50 MW and 2 x120 MW)

2010-11	2011-12	2012-13
78%	78.25%	78.50%

NOTE: The norms under (b) above are relaxed norms.

33.2 **Gross Station Heat Rate**

A. Existing Thermal Generating Station

(a) Existing Coal-based Thermal Generating Stations, other than those covered under clauses (b) and (c) below

200/210/250 MW Sets	**500 MW Sets (Sub-critical)**
2500 KCal/kWh	2425 kCal/kWh

(b) Hasdeo Thermal Power Station Korba (4 x 210 MW) the GHR 2650 Kcal/kwh

(c) For Korba East Complex TPS (4 x 50 MW and 2 x120 MW) -

2010-11	2011-12	2012-13
2975 Kcal/kwh	2950 Kcal/kwh	2925 Kcal/kwh

Note 1

In respect of 500 MW and above units where the boiler feed pumps are electrically operated, the gross station heat rate shall be 40 kCal/kWh lower than the gross station heat rate specified above.

Note 2

For the generating stations having combination of 200/210/250 MW sets and 500 MW and above sets, the normative gross station heat rate shall be the weighted average gross station heat rate of the combinations.

Note 3

Norms at (b) above are the relaxed norms.

B. New Thermal Generating Station achieving COD on or after 01.04.2010

(a) Coal-based Thermal Generating Stations
= 1.065 X Design Heat Rate (kCal/kWh)

Where the Design Heat Rate of a unit means the unit heat rate guaranteed by the supplier at conditions of 100% MCR, zero percent make up, design coal and design cooling water temperature/back pressure.

Provided that the design heat rate shall not exceed the following maximum design unit heat rates depending upon the pressure and temperature ratings of the units:

Pressure Rating (Kg/cm2)	150	170	170	247	247
SHT/RHT (0C)	535/535	537/537	537/565	537/565	565/593
Type of BFP	Electrical Driven	Turbine driven	Turbine driven	Turbine driven	Turbine driven
Max Turbine Cycle Heat rate (kCal/kWh)	1955	1950	1935	1900	1850

Min. Boiler Efficiency					
Sub-Bituminous Indian Coal	0.85	0.85	0.85	0.85	0.85
Bituminous Imported Coal	0.89	0.89	0.89	0.89	0.89
Max Design Unit Heat rate (kCal/kWh)					
Sub-Bituminous Indian Coal	2300	2294	2276	2235	2176
Bituminous Imported Coal	2197	2191	2174	2135	2079

Provided further that in case pressure and temperature parameters of a unit are different from above ratings, the maximum design unit heat rate of the nearest class shall be taken:

Provided also that where unit heat rate has not been guaranteed but turbine cycle heat rate and boiler efficiency are guaranteed separately by the same supplier or different suppliers, the unit design heat rate shall be arrived at by using guaranteed turbine cycle heat rate and boiler efficiency.

Provided also that if one or more units were declared under commercial operation prior to 01.04.2010, the heat rate norms for those units as well as units declared under commercial operation on or after 01.04.2010 shall be lower of the heat rate norms arrived at by above methodology and the norms as per the regulation 33.2.A.

Note: In respect of units where the boiler feed pumps are electrically operated, the maximum design unit heat rate shall be 40 kCal/kWh lower than the maximum design unit heat rate specified above with turbine driven BFP.

33.3 **Secondary fuel oil consumption**

(a) Coal-based generating stations other than at (b) & (c) below : 1.0 ml/kWh

(b) Coal Based generating stations having unit size less than 200 MW : 1.5 ml / kwh

(c) Korba East Complex TPS (4x50MW+ 2x 120 MW) :

2010-11	2011-12	2012-13
2.25 ml /kwh	2.15 ml /kwh	2.00 ml /kwh

33.4 Auxiliary Energy Consumption

(a) Coal-based generating stations except at (b) below:

		With Natural Draught cooling tower or without cooling tower
(i)	200 MW series	8.5%
(ii)	500 MW & above	
	Steam driven boiler feed pumps	6.0%
	Electrically driven boiler feed pumps	8.5%

Provided further that for thermal generating stations with induced draft cooling towers, the norms shall be further increased by 0.5%.

(b) Considering the previous performance of power stations and the design aspects, the auxiliary consumption for the existing two power stations of CSPGCL shall be as follows:

(i) Hasdeo Thermal power stations (4x210MW) - 9%

(ii) Korba East complex TPS (4x50MW+ 2x 120 MW). -

2010-11	2011-12	2012-13
10.4 %	10.35 %	10.3 %

Note: 1. Norms at b(i) above are the relaxed norms.
2. The normative operating parameters for Korba (East) complex TPS may be improved or further relaxed on account of coal quality during annual performance review.

Norms of operation for hydro generating, small hydro generating and Baggase based generating stations

34. A. The norms of operation as given hereunder shall apply to hydro generating station:

(i) Normative annual plant availability factor (NAPAF) for hydro generating stations

(1) Normative annual plant availability factor (NAPAF) for hydro generating stations shall be determined by the Commission as per the following criteria:

(a) Storage and Pondage type plants with head variation between Full Reservoir Level (FRL) and Minimum Draw Down Level (MDDL) of up to 8%, and where plant availability is not affected by silt : 90%

(b) Storage and Pondage type plants with head variation between FRL and MDDL of more than 8%, where plant availability is not affected by silt : Plant-specific allowance to be provided in NAPAF for reduction in MW output capability as reservoir level falls over the months. As a general guideline the allowance on this account in terms of a multiplying factor may be worked out from the projection of annual average of net head, applying the formula: (Average head / Rated head) + 0.02

Alternatively in case of a difficulty in making such projection, the multiplying factor may be determined as: (Head at MDDL/Rated head) x 0.5 + 0.52

(c) Pondage type plants where plant availability is significantly affected by silt:85%.

(d) Run-of-river type plants : NAPAF to be determined plant-wise, based on 10-day design energy data, moderated by past experience where available/relevant.

(2) A further allowance may be made by the Commission in NAPAF determination under special circumstances, e.g. abnormal silt problem or other operating conditions, and known plant limitations.

(3) In case of a new hydro electric project the developer shall have the option of approaching the Commission in advance for fixation of NAPAF based on the principles enumerated in sub-clauses (1) and (2) of this regulation.

(ii) **Auxiliary Energy Consumption (AUX):**

(a) Surface hydro generating stations

(i) with rotating exciters mounted on the generator shaft : 0.7%

(ii) with static excitation system : 1.0%

(b) Underground hydro generating stations

(i) with rotating exciters mounted on the generator shaft : 0.9 %

(ii) with static excitation system : 1.2 %

34. B. The norms of operation for Baggase based generating station(s) and small hydel plants shall be same as applicable to Biomass based generating stations and small hydel plants as per the relevant orders and regulations of the Commission.

Norms of operation for transmission system

35. NORMATIVE ANNUAL TRANSMISSION SYSTEM AVAILABILITY FACTOR (NATAF) shall be as under:

(1) AC system :

2010-11	2011-12	2012-13
97 %	97.5 %	98 %

(2) HVDC bi-pole links : 92%

(3) HVDC back-to-back Stations : 95%

36. AUXILIARY ENERGY CONSUMPTION IN SUB-STATION:

36.1 AC System: The charges for auxiliary energy consumption in the AC sub-station for the purpose of air-conditioning, lighting and consumption in other equipment shall be borne by the transmission licensee and included in the normative operation and maintenance expenses.

36.2 HVDC sub-station: For auxiliary energy consumption in HVDC sub-stations, the Central Government may allocate an appropriate share from one or more ISGS. The charges for such power shall be borne by the transmission licensee and are included in the normative operation and maintenance expenses.

37. TRANSMISSION LOSS AND ITS TREATMENT:

37.1 Transmission losses at different voltage levels shall be calculated as the difference between the sum of all energy (X) injected into the transmission system from different interface points and the sum of energy transmitted to distribution licensee(s) and consumer(s)(Y) connected with transmission system. Transmission losses expressed as a percentage at different voltage levels shall be the transmission loss upto that voltage level as a percentage of the total energy injected into the transmission system.

$$\text{Transmission loss (\%)} = \frac{(X - Y) \times 100}{X}$$

37.2 Transmission losses at normative levels as approved by the Commission shall be debitable to energy account of users of the transmission system. In case the actual transmission losses exceed the normative loss levels approved by the Commission, such excess loss shall be to the account of the transmission licensee and the transmission licensee shall compensate the distribution licensee at the weighted average cost of power purchase in that financial year.

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Chapter – 5

ARR & TARIFF FOR WHEELING AND RETAIL SUPPLY

38. GENERAL:

38.1 The distribution licensee may segregate its accounts into wheeling business and retail supply business. The ARR for wheeling business would be used to determine wheeling charges and the ARR for retail supply business to determine retail supply tariffs.

38.2 For such period until accounts are segregated, the licensee will prepare an "allocation statement" showing apportionment of costs and revenues to these two businesses. The statement will be supported with an explanation of the methodology used for such allocations.

39. ESTIMATION OF SALES

39.1 The licensee shall submit forecast of restricted demand (in MW) and unrestricted demand (in MW) for all consumer categories together and sale of electricity (in MU) for different categories of consumers in his area of supply, for all the years of the control period. The forecasts for category-wise sale of electricity shall generally be worked out on the basis of general assessment and CAGR or any other better statistical method.

39.2 The sales forecast for unmetered consumer categories, if any, shall be validated with norms approved by the Commission on the basis of a proper study carried out by the licensee and reflected in revenue statements.

The Commission shall examine the forecasts for their reasonableness based on growth in the number of consumers, pattern of consumption, losses and demand of electricity in previous years and anticipated growth in the next year and any other factor, which the Commission may consider relevant and approve the sales forecast with such modifications as deemed fit.

39.3 The distribution licensee shall also indicate category-wise open access customers. The demand and energy wheeled for them shall be shown separately for -

(a) supply within its area of supply; and

(b) supply outside its area of supply.

40. DISTRIBUTION LOSS AND ITS TREATMENT:

40.1 The distribution loss at a particular voltage level shall be the difference between the energy injected into the distribution system at that voltage level and the sum of energy sold to all its consumers at that voltage level and the energy delivered below that voltage level. Energy sold shall be the sum of metered sales and assessed unmetered sales, if any, based on approved norms.

40.2 The Commission shall approve a realistic and achievable loss target for each year of the control period based on a detailed study to be undertaken by the licensee. In the absence of such study, the Commission shall set such target as it considers reasonable on the basis of information on line losses submitted by the licensee.

40.3 The Commission shall also fix targets, both long-term and short-term, for loss reduction to bring down the loss level gradually to acceptable norms of efficiency.

40.4 To generate local consensus for effective action for better governance, area/ locality specific surcharge for higher Distribution loss may be considered. The Commission may also encourage suitable local area based incentive and disincentive schemes for the staff of the utilities linked to the reduction of losses, as per the provision of para 8.2.1(2) of the Tariff Policy.

41. ESTIMATION OF REQUIREMENT OF PURCHASE OF POWER

41.1 The estimation of electricity required to be purchased by the licensee shall be worked out based on the estimated energy sales forecast of the licensee and the approved distribution losses for the years of the control period and the transmission losses approved by the Commission for the transmission licensee for the control period.

41.2 The Commission shall scrutinize and approve the requirement for purchase of power with such modifications as deemed fit, for each year of the control period.

42. ANNUAL REVENUE REQUIREMENT (ARR):

The ARR for wheeling business and retail supply business of the distribution licensee for each year of the control period shall comprise of the following, namely:

(a) Power Purchase Costs

(b) Transmission and SLDC Charges

(c) Operation and maintenance expense

(d) Depreciation

(e) Interest on loan capital

(f) Interest on working capital

(g) Return on equity

(h) Taxes on income

(i) Other expenses if any

Note: Non-tariff income as specified in regulation 65, shall be subtracted from the sum of above (a to i) to arrive at ARR

43. NORMS OF OPERATION & PERFORMANCE TARGETS:

43.1 Based on the proposal, information and data submitted by the distribution licensee, the Commission is to set the following performance targets in the tariff order:

(a) Distribution loss reduction trajectory

(b) Energy efficiency and demand-side management measures.

(c) Arrears reduction / improvement in collection efficiency.

43.2 The Commission may consider incentivising the licensee for achieving better performance targets.

44. COST OF POWER PURCHASE:

The distribution licensee shall be allowed to recover the cost of power it procures from all sources including the power procured from the State owned generating stations, independent power producers, Central generating stations, Captive generating plant, renewable energy sources and others, for supply of power to consumers, based on the load forecast approved by the Commission for each year of the control period.

44.1 Approved retail sales level shall be grossed up by normative level of T&D losses as given in the approved loss trajectory for the purpose of arriving at the quantity of energy to be purchased for estimating the power purchase cost in the ARR.

44.2 While approving the cost of power purchase, the Commission shall determine the quantum of power to be purchased from various sources in accordance with the principles of merit order schedule and despatch based on a ranking of all approved sources of supply in the order of effective cost of power purchase.

44.3 All power purchase costs will be considered legitimate unless it is established that the merit order principle has been violated or power has been purchased at unreasonable rates.

44.4 Foreign exchange variation risk, if any, shall not be a pass through. However, in the case of existing PPAs which provide for payment of foreign exchange rate variation, the same shall be allowed to be included in the power purchase costs during the currency of such contracts.

45. TRANSMISSION CHARGES AND SLDC CHARGES:

45.1 The distribution licensee shall be allowed to recover transmission charges payable to a transmission licensee for access to and use of intra-state / inter-state transmission system in accordance with the tariff approved by the appropriate Commission.

45.2 The distribution licensee shall also be allowed to recover the expenses at the approved level:

(a) the charges for intervening transmission facilities;

(b) wheeling charges for use of distribution system of other distribution licensee(s);

(c) the charges for access and use of inter-state transmission system in accordance with the tariffs determined by CERC; and

(d) the fees and charges payable to the RLDC and SLDC as may be specified by the appropriate Commission..

46. OPERATION AND MAINTENANCE EXPENSES:

46.1 Operation and maintenance (O&M) expenses shall mean the total of all expenditure under the following heads:

a. Employee costs;

b. Repairs and Maintenance (R&M) expenses; and

c. Administrative and General (A&G) costs.

46.2 The distribution company in its filings shall submit the O&M expenses in above heads separately on the basis of available audited / un audited accounts for the previous five years preceding the base year and also for the base year. The O&M expenses for the base year will be used for projecting the expenses for each year of the control period.

47. INTEREST AND FINANCE CHARGES:

47.1 Interest and finance charges on loan capital and working capital shall be computed in accordance with regulations 23 and 25 respectively.

47.2 For the purpose of working out interest, working capital of distribution licensee shall cover:

(a) Operation and maintenance expenses for one month;

(b) Maintenance spares @ 15 % of O& M expenses ; and

(c) Receivables equivalent to two month's average revenue.

48. RETURN ON EQUITY: Considering the provisions of clause 5.3. a) of the Tariff Policy, the commission may allow return on equity as per regulation 22 with appropriate modification taking in to view the higher risk involved in the business of distribution. Further the commission may also consider the recommendations of the Forum of Regulators or any competent Govt. Authority regarding the distribution margin.

49. DEPRECIATION:

Depreciation of the assets of distribution licensee shall be computed in the manner prescribed in Regulation 24 of these Regulations.

50. BAD AND DOUBTFUL DEBT:

The Commission may consider a provision for writing off of bad and doubtful debts of distribution licensee. As a normative provision 1% of yearly revenue from the retail supply business shall be allowed as bad and doubtful debt subject to actual writing off of bad and doubtful debts in the previous year.

51 RETAIL SUPPLY TARIFF:

The retail supply tariff shall be cost reflective and designed to recover the Aggregate Revenue Requirement of the distribution licensee approved by the Commission for each year of the control period.The Commission may reset the supply tariff annually to rebalance the cross-subsidies.To promote demand side management and various energy conservation measures, two part tariffs featuring separate fixed and variable charges and a differential tariff for peak and off-peak hours may be implemented.The Commission shall stipulate the broad classification of consumers and time frame for implementation of TOD tariff. While stipulating differential tariffs, the Commission may also indicate the peak, off-peak periods.The Commission may provide incentives to encourage metering and billing based on metered tariffs, particularly for consumer categories that are presently unmetered.The tariff design for various consumer categories shall be based on total average cost of supply as envisaged in the Tariff Policy.

52. WHEELING CHARGES:

52.1 The wheeling charges payable by the users of the distribution system shall be designed to recover the ARR for wheeling business as approved by the Commission for each year of the control period.Wheeling charges so worked out shall be apportioned supply voltage-wise. However, till adequate and reliable information is available, the wheeling charges may be determined at a uniform rate irrespective of voltage.

52.2 The wheeling charges shall be determined on the basis of approved costs and sales/ demand forecast. The total contract demand/ connected load may be the basis for determination of wheeling charges to take care of the sales variation.

52.3 The users of the distribution system shall bear the distribution losses at the respective voltage levels to provide for adjustment of losses in the system in kind in addition to the wheeling charges.

52.4 The wheeling charges shall be levied on contracted energy, calculated on the basis of 100 % load factor on contracted power for wheeling.

53. SUBSIDY BY GOVERNMENT:

If the State Government decides to subsidize any consumer or class of consumers, it shall pay, as per the provisions of Section 65 of the Act, the amount in advance to compensate the licensee affected by the grant of such subsidy in the manner as specified by the Commission.Provided that no such direction of the State Government to grant subsidy shall be operative if the payment is not made in accordance with the provisions contained in the Section 65 of the Act and the tariff fixed by the Commission shall be applicable from the date of issue of orders by the Commission in this regard.

53.1 To ensure implementation of the provision of the Act, the Commission shall determine the tariff initially, without considering the subsidy commitment by the State Government and subsidised tariff shall be arrived at thereafter considering the subsidy by the State Government for the respective categories of consumers.

53.2 There shall not be any adjustment of the due subsidy against outstanding loans of the State Government, however, the adjustment of subsidy against electricity duty actually collected by the CSPDCL / distribution licensee may be allowed.

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CHAPTER – 6

SCHEDULING, ACCOUNTING AND BILLING

54. **SCHEDULING:** The methodology for scheduling and dispatch for the generating station shall be as specified in the Chhattisgarh State Electricity Grid Code,(as amended from time to time. Provisions of the UI Regulations and the IEGC of CERC shall also be applicable only for the issues which are not covered in the relevant regulations of this Commission including the State Grid Code. **METERING AND ACCOUNTING.** The provisions of the Chhattisgarh State Electricity Grid Code, as amended from time to time shall be applicable.

55. **BILLING AND PAYMENT OF CHARGES:**

(1) Bills shall be raised for capacity charge, energy charge and the transmission charge on monthly basis by the generating company and the transmission licensee/STU in accordance with these regulations, and payments shall be made by the beneficiaries or the transmission customers directly to the generating company or the transmission licensee, as the case may be.

Note

The CSPGCL presently supplies power to CSPDCL through non ABT mechanism. The supply of power by CSPGCL to CSPDCL through ABT mechanism will be introduced for the first time. In case of difficulties experienced to start with, the Commission may allow it as trial run for a period, as specified in the tariff order. During such period all the commercial settlements will be based on the existing arrangement or as specified by the Commission in the tariff order.

(2) Transmission charges corresponding to any plant capacity for which a beneficiary has not been identified and contracted shall be paid by the concerned generating company.

(3) The billing to the retail consumers shall be done in accordance with the provisions specified in the CG supply code 2005.

(4) In case, the State Govt. does not pay the due amount of subsidy in time and in cash for the retail supply consumers, the CSPDCL / distribution licensee shall issue the bill on the basis of the tariff determined by the Commission.

56. REBATE:

57.1 For payment of bills of the generating company and the transmission licensee through letter of credit on presentation, a rebate of 2% shall be allowed.

57.2 Where payments are made other than through letter of credit within a period of 30 days of presentation of bills by the generating company or the transmission licensee, a rebate of 1% shall be allowed.

57. LATE PAYMENT SURCHARGE:

58.1 In case the payment of any bill for charges payable under these Regulations is delayed by a beneficiary beyond a period of 60 days from the date of billing a late payment surcharge at the rate of 1.25% per month shall be levied by the generating company or the transmission licensee.

58.2 Late payment surcharge for the retail consumer shall be recoverable as per the provisions of relevant tariff order.

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CHAPTER – 7

MISCELLANEOUS PROVISIONS

58. Sharing of CDM Benefits. The proceeds of carbon credit from approved CDM project shall be shared in the following manner, namely-

(a) 100% of the gross proceeds on account of CDM to be retained by the project developer in the first year after the date of commercial operation of the generating station or the transmission system, as the case may be;

(b) in the second year, the share of the beneficiaries shall be 10% which shall be progressively increased by 10% every year till it reaches 50%, thereafter the proceeds shall be shared in equal proportion, by the generating company or the licensee, and the beneficiaries / consumers as the case may be.

59. **NORMS OF OPERATION TO BE CEILING NORMS:** Norms of operation specified in these regulations are the ceiling norms and shall not preclude the generating company or the transmission licensee or the distribution licensee, as the case may be, and the beneficiaries and the long-term transmission customers from agreeing to the improved norms of operation and in case the improved norms are agreed to, such improved norms shall be applicable for determination of tariff.

60. **DEVIATION FROM NORMS:**

Tariff for sale of electricity by the generating company or for transmission charges of the transmission licensee, as the case may be, may also be determined in deviation of the norms specified in these regulations subject to the conditions that-

(a) the levelised tariff over the useful life of the project on the basis of the norms in deviation does not exceed the levelised tariff calculated on the basis of the norms specified in these regulations; and

(b) Any deviation shall come into effect only after approval by the Commission, for which an application shall be made by the generating company or the transmission licensee, as the case may be.

Explanation - For the purpose of calculating the levelised tariff referred to in sub-clause (a) of regulation 61, the discounting factor shall be as notified by the CERC from time to time.

61. **TAX ON INCOME:** Tax on the income streams of the generating company or the licensee, as the case may be, shall not be recovered from the beneficiaries, or the intra-state transmission customers or consumers, as the case may be:

Provided that the deferred tax liability, excluding Fringe Benefit Tax, for the period up to 31st March, 2010 whenever it materializes, shall be recoverable directly from the beneficiaries or the intra-state transmission customers or consumers, as the case may be.

62. **FOREIGN EXCHANGE RATE VARIATION:**

63.1 The generating company or the transmission licensee or the distribution licensee, as the case may be, may hedge foreign exchange exposure in respect of the interest on foreign currency loan and repayment of foreign loan acquired for the generating station or the transmission or distribution system, in part or full in the discretion of the generating company or the licensee.

63.2 Every generating company and licensee shall recover the cost of hedging of foreign exchange rate variation corresponding to the normative foreign debt, in the relevant year on year-to-year basis as expense in the period in which it arises and extra rupee liability corresponding to such foreign exchange rate variation shall not be allowed against the hedged foreign debt.

63.3 To the extent the generating company or the licensee or the distribution licensee is not able to hedge the foreign exchange exposure, the extra rupee liability towards interest payment and loan repayment corresponding to the normative foreign currency loan in the relevant year shall be permissible provided it is not attributable to the generating company or the licensee or the distribution licensee or its suppliers or contractors.

63.4 Every generating company and the licensee shall recover the cost of hedging and foreign exchange rate variation on year-to-year basis as income or expense in the period in which it arises.

63. **RECOVERY OF COST OF HEDGING FOREIGN EXCHANGE RATE VARIATION:** Recovery of cost of hedging and foreign exchange rate variation shall be made directly by the generating company or the transmission licensee or the distribution licensee, as the case may be, from the beneficiaries or the transmission customers, as the case may be, without making any application before the Commission:

Provided that in case of any objections by the beneficiaries to the amounts

claimed on account of cost of hedging or foreign exchange rate variation, the generating company or the transmission licensee or the distribution licensee, as the case may be, may make an appropriate application before the Commission for its decision.

64. **NON-TARIFF INCOME:** Any income being incidental to the business of the licensee /generating company derived from sources, including but not limited to the disposal of assets, income from investments, rents, open access charges, parallel operation charges penalties for over/under-utilization of system and any other miscellaneous receipts but other than income from sale of energy, shall constitute the non tariff income.

65. To avoid the possibility of abnormal variations in tariff, the net profit earned by the Chhattisgarh State Power Distribution Company from operations of sale of electricity to other than the consumers of licensed area, shall be credited to the "Tariff stabilization fund ", as defined in the regulation 3.42.

66. **INCENTIVE AND DISINCENTIVE SCHEME:** - To accelerate the performance, the licensee / generating company shall prepare and implement the scheme of allowing incentive and disincentive to the employee after taking approval from the Commission.

67. **APPLICATION FEE AND THE PUBLICATION EXPENSES:** The application filing fee and the expenses incurred on publication of notices in the application for approval of tariff, , be allowed to be recovered by the generating company or the transmission licensee/STU or the distribution licensee, as the case may be, directly from the beneficiaries or the transmission customers, as the case may be:

68. **POWER TO RELAX:** The Commission, for reasons to be recorded in writing, may relax any of the provisions of these regulations on its own motion or on an application made beforc it by an interested person..

69. **SAVINGS AND REPEAL :**

70. 1Nothing in these Regulations shall be deemed to limit or otherwise impede the inherent power of the Commission to revise/review and make such orders as may be necessary, in the absence of sufficient data, to meet ends of justice or to prevent abuses of the process of the Commission

70.2 Nothing in these Regulations shall impede the Commission from adopting, in conformity with the provisions of the Act, a procedure, which is at variance with any of the provisions of these Regulations, if the Commission, in view of the special

circumstances of a matter or class of matters, and for reasons to be recorded in writing, deems it necessary or expedient for dealing with such a matter or class of matters.

70.3 These regulations shall supersede earlier regulations on the subject i.e. CSERC (Terms and conditions of determination of tariff according to Multi-year tariff principles) Regulations, 2008.

70. POWER TO REMOVE DIFFICULTIES:

If any difficulty arises in giving effect to any of the provisions of these regulations, the Commission may, of its own motion or otherwise by an order and after giving a reasonable opportunity to those likely to be affected by such order, make such provisions, not inconsistent with these regulations or the Act, as may appear to be necessary for removing those difficulties.

71. POWER TO AMEND:

The Commission may, at any time, add, alter, vary, modify or amend any of the provisions of these Regulations.

Note: In case of any difference in the interpretation or understanding of the provisions of the Hindi version of these Regulations with that of the English version (the original version), the later will prevail and in case of any dispute in this regard, the decision of the Commission shall be final and binding.

By order of the Commission,

(N. K. Rupwani)
Secretary.

Appendix-I

Timeline for completion of Projects

(Refer to Regulation 22)

1. The completion time schedule shall be reckoned from the date of project commencing as decided by the Board (of the generating company or the transmission licensee) at the time of commencement of the project, up to the date of commercial operation of the units or block or element of transmission project as applicable.

2. The time schedule has been indicated in months in the following paragraphs and tables:

A Thermal Power Projects

Coal/Lignite Power Plant

Unit size 200/210/250/300/330 MW and 125 MW CFBC technology

(a) 33 months for green field projects. Subsequent units at an interval of 4 months each.

(b) 31 months for extension projects. Subsequent units at an interval of 4 months each.

Unit size 250 MW CFBC technology

(a) 36 months for green field projects. Subsequent units at an interval of 4 months each.

(b) 34 months for extension projects. Subsequent units at an interval of 4 months each.

Unit size 500/600 MW

(a) 44 months for green field projects. Subsequent units at an interval of 6 months each.

(b) 42 months for extension projects. Subsequent units at an interval of 6 months each.

Unit size 660/800 MW

(a) 52 months for green field projects. Subsequent units at an interval of 6 months each.

(b) 50 months for extension projects. Subsequent units at an interval of 6 months each.

Combined Cycle Power Plant

Gas Turbine size upto 100 MW (ISO rating)

(a) 26 months for first block of green field projects. Subsequent blocks at an interval of 2 months each.

(b) 24 months for first block of extension projects. Subsequent units at an interval of 2 months each.

Gas Turbine size above 100 MW (ISO rating)

(a) 30 months for first block of green field projects. Subsequent blocks at an interval of 4 months each.

(b) 28 months for first block of extension projects. Subsequent units at an interval of 4 months each.

B. Hydro Electric Projects

The qualifying time schedule for hydro electric projects shall be as stated in the original concurrence issued by the Central Electricity Authority under section 8 of the Act.

C. Transmission Schemes

Qualifying time schedules in months

S. No.	Transmission Work	Plain Area (months)	Hilly Terrain (months)	Extensive forest area /very difficult Terrain (months)
a	765 kV S/C Transmission line	30	36	40
b	+/-500 KV HVDC Transmission line	24	30	34
c	400 KV D/C Quad Transmission line	32	38	42
d	400 KV D/C Triple Transmission line	30	36	40
e	400 KV D/C Twin Transmission line	28	34	38
f	400 KV S/C Twin Transmission line	24	30	34
g	220 KV D/C Twin Transmission line	28	34	38
h	220 KV D/C Transmission line	24	30	34
i	220 KV S/C Transmission line	20	26	30
j	New 220 KV AC Sub-Station	18	21	24
k	New 400 KV AC Sub-Station	24	27	30
l	New 765 kV AC Sub-Station	30	34	$
m	HVDC bi-pole terminal	36	38	-
n	HVDC back-to-back	26	28	-

$ No 765 KV sub-Station has been planned in difficult terrain

Notes:

(i) In case a scheme having combination of the above mentioned types (plain / hilly) of projects, the qualifying time schedule of the activity having maximum time period shall be considered for the scheme as a whole.

(ii) In case a transmission line falls in plain as well as in hilly terrain / extensive forest area / very difficult terrain, the composite qualifying time schedule shall be calculated giving proportional weightage to the line length falling in each area.

(iii) The Commission may review the qualifying time by giving due consideration to length of line.

Appendix-II

Depreciation Schedule

Sr. No.	Asset Particulars	Depreciation Rate (Salvage Value=10%)
		SLM
A	Land under full ownership	0.0%
B	Land under lease	
(a)	For investment in the land	3.34%
(b)	For cost of clearing the site	3.34%
(c)	Land for reservoir in case of hydro generating station	3.34%
C	Assets purchased new	
(a)	Pl & Machinery in generating stations	
(i)	Hydro electric	5.28%
(ii)	Steam electric NHRB & waste heat recovery boilers	5.28%
(iii)	Diesel electric and gas plant	5.28%
(b)	Cooling towers & circulating water systems	5.28%
(c)	Hydraulic works forming part of the Hydro	
(i)	Dams, Spilways, Weirs, Canals, Reinforced concrete flumes and siphons	5.28%
(ii)	Reinforced concrete pipelines and surge tanks, steel pipelines, sluice gates, steel surge tanks, hydraulic control valves and hydraulic works	5.28%
(d)	Building & Civil Engineering works of a	
(i)	Offices and showrooms	3.34%
(ii)	Containing thermo-electric generating plant	3.34%
(iii)	Containing hydro-electric generating plant	3.34%
(iv)	Others	3.34%
(e)	Transformers, Kiosk, Sub-station equipment & other fixed apparatus (including plant	
(i)	Transformers including foundations having rating of 100 KVA and over	5.28%
(ii)	Others	5.28%
(f)	Switchgear including cable connections	5.28%
(g)	Lightning arrestor	5.28%
(i)	Station type	5.28%
(ii)	Pole type	5.28%
(iii)	Synchronous condenser	5.28%
(h)	Batteries	5.28%
(i)	Underground cable including joint boxes and disconnected boxes	5.28%

(ii)	Cable duct system	5.28%
i	Overhead lines including cable support	
(i)	Lines on fabricated steel operating at terminal voltages higher than 66 KV	5.28%
(ii)	Lines on steel supports operating at terminal voltages higher than 13.2 KV but not exceeding 66 KV	5.28%
(iii)	Lines on steel on reinforced concrete support	5.28%
(iv)	Lines on treated wood support	5.28%
(j)	Meters	5.28%
(k)	Self propelled vehicles	9.50%
(l)	Air Conditioning Plants	
(i)	Static	5.28%
(ii)	Portable	9.50%
M (i)	Office furniture and furnishing	6.33%
(ii)	Office equipment	6.33%
(iii)	Internal wiring including fittings and apparatus	6.33%
(iv)	Street Light fittings	5.28%
n	Apparatus let on hire	
(i)	Other than motors	9.50%
(ii)	Motors	6.33%
o	Communication equipment	
(i)	Radio and high frequency carrier system	6.33%
(ii)	Telephone lines and telephones	6.33%
p	I.T. Equipments	15.00%
q	Any other assets not covered above	5.28%

Appendix – III

Procedure for Calculation of Transmission System Availability Factor for a Month

1. Transmission system availability factor for a calendar month (TAFM) shall be calculated by the respective transmission licensee, got verified by the concerned RLDC and certified by the Member-Secretary, Regional Power Committee of the region concerned, separately for each AC and HVDC transmission system and grouped according to sharing of transmission charges.

2. AFM, in percent, shall be equal to (100 – 100 x NAFM), where NAFM is the non-availability factor in per unit for the month, for the transmission system / sub-system.

3. NAFM for A.C. systems / sub-systems shall be calculated as follows :

4.

$$NAFM = \left[\sum_{l=1}^{L} (OH_l \times Cktkm_l \times NSC_l) + \sum_{t=1}^{T} (OH_t \times MVA_t \times 2.5) + \sum_{r=1}^{R} (OH_r \times MVAR_r \times 4) \right] \div THM \times \left[\sum_{l=1}^{L} (Cktkm_l \times NSC_l) + \sum_{t=1}^{T} (MVA_t \times 2.5) + \sum_{r=1}^{R} (MVAR_r \times 4) \right]$$

Where

l	identifies a transmission line circuit
t	identifies a transformer / ICT
r	identifies a bus reactor, switchable line reactor or SVC
L	= total number of line circuits
T	= total number of transformers and ICTs
R	= total number of bus reactors, switchable line reactors and SVCs

OH = Outage hours or hours of non-availability in the month, excluding the duration of outages not attributable to the transmission licensee, if any, as per clause (5).

Cktkm = Length of a transmission line circuit in km

NSC = Number of sub-conductors per phase

MVA = MVA rating of a transformer / ICT

MVAR = MVAR rating of a bus reactor, switchable line reactor or an SVC (in which case it would be the sum of inductive and capacitive capabilities).

THM = Total hours in the month.

4. NAFM for each HVDC system shall be calculated separately, as follows :

NAFM = [$\sum$ (TCR x hours)] ÷ [THM x RC]

Where

TCR = Transmission capability reduction of the system in MW

RC = Rated capacity of the system in MW.

For the above purpose, the HVDC terminals and directly associated EHV / HVDC lines of an HVDC system shall be taken as one integrated system.

5. The transmission elements under outage due to following reasons shall be deemed to be available:

(i) Shut down availed for maintenance or construction of elements of another transmission scheme. If the other transmission scheme belongs to the transmission licensee, the Member-Secretary, RPC may restrict the deemed availability period to that considered reasonable by him for the work involved.

(ii) Switching off of a transmission line to restrict over voltage and manual tripping of switched reactors as per the directions of RLDC.

6. Outage time of transmission elements for the following contingencies shall be excluded from the total time of the element under period of consideration.

i) Outage of elements due to acts of God and force majeure events beyond the control of the transmission licensee. However, onus of satisfying the Member

Secretary, RPC that element outage was due to aforesaid events and not due to design failure shall rest with the transmission licensee. A reasonable restoration time for the element shall be considered by Member Secretary, RPC and any additional time taken by the transmission licensee for restoration of the element beyond the reasonable time shall be treated as outage time attributable to the transmission licensee. Member Secretary, RPC may consult the transmission licensee or any expert for estimation of reasonable restoration time. Circuits restored through ERS (Emergency Restoration System) shall be considered as available.

ii) Outage caused by grid incident/disturbance not attributable to the transmission licensee, e.g. faults in substation or bays owned by other agency causing outage of the transmission licensee's elements, and tripping of lines, ICTs, HVDC, etc. due to grid disturbance. However, if the element is not restored on receipt of direction from RLDC while normalizing the system following grid incident/disturbance within reasonable time, the element will be considered not available for the period of outage after issuance of RLDC's direction for restoration.

संचालक, मुद्रण तथा लेखन सामग्री, छत्तीसगढ़ द्वारा शासकीय क्षेत्रीय मुद्रणालय, राजनांदगांव से मुद्रित तथा प्रकाशित—2010.